Before the
Rhode Island Public Utilities Commission

Proceeding on the Narragansett Electric	)	
Company d/b/a National Grid Proposed	)	Dockets No. 4770 and 4780
Tariff Changes	)	

Testimony of

Jonathan E. Schrag

Supporting the Settlement Agreement

On Behalf of

The Division of Public Utilities and Carriers

June 6, 2018

I. INTRODUCTION

Q. Please identify yourself for the record.

A. My name is Jonathan E. Schrag. I am the Deputy Administrator for the Division of Public Utilities and Carriers ("Division"), reporting directly to the Administrator. I have been in that role since October 2016. In that role I have responsibility to develop and review DPUC regulatory filings and to work with staff across the Division to advance regulatory policy. Over the last two years I have worked extensively on electricity and gas matters related to National Grid. I also am responsible for supervising the regulatory and rate staff, and managing outside consultants hired by the Division to assist in the review of filings by the entities regulated by the Division and the Public Utilities Commission ("Commission").

Q. Please describe your professional background.

A. I have worked in energy policy for the last 15 years, including as Executive Director of the Lenfest Center for Sustainable Energy at Columbia University, Executive Director of the Regional Greenhouse Gas Initiative, Senior Fellow in Energy of the Guarini Institute of NYU School of Law, and Deputy Commissioner for Energy of the Connecticut Department of Energy and Environmental Protection. From 1997 to 2002 I was a graduate fellow enrolled in the Harvard University Department of History investigating the electrification of Mexico. I received an AB degree cum laude in History from Harvard University in 1993.

Q. What was your role in the negotiation of the Settlement Agreement that was filed with the Commission?

A. I was the lead negotiator on behalf of the Division in the settlement discussions.

Q. What is the purpose of your testimony?

A. During a procedural conference discussing the expected filing of the Settlement Agreement, Commission counsel requested parties who would be signatories to the Settlement Agreement to file testimony in support of the Settlement Agreement. My testimony is provided in response to that request.

II. OVERVIEW

Q. How would you categorize the scope of this Settlement Agreement, compared to other types of settlements filed with the Commission of which you are familiar?

A. This settlement is far more complex and comprehensive than a traditional settlement that typically results in parties agreeing to new rates during a base distribution rate case.

Q. Can you elaborate on this observation that this settlement is more complex and comprehensive than settlements of previous rate cases?

A. Rhode Island's electric system is in the process of significant change as it incorporates both new grid facing technologies, new customer facing technologies and new demands to integrate significant variable carbon free energy resources. The Division understands this rate case to be one important step in that process of change. Many additional steps will be needed over the coming decade. However, with this rate case, National Grid and the Division and all intervenors articulate a direction for change which the Commission may put into motion and continue to steer over the coming decade.

Q. How does this proposed settlement benefit Rhode Island ratepayers?

A. There are six aspects of this settlement that will provide near and long-term benefits to ratepayers.

First, the settlement proposes a multi-year rate plan that provides an essential planning and budget discipline tool for the Company as it embarks on an accelerated pace of technology change. Based on the expert testimony of Tim Woolf, the Division believes this budget and planning tool is a necessary component to help the utility make the transition to seek least cost energy supply in a way consistent with the long-articulated goals of stakeholders and policymakers in Rhode Island.

Second, the settlement is designed to control and temper the trend of capital over-spending through a new capital efficiency incentive mechanism. This represents a significant structural victory for ratepayers to ensure the ISR does not create an open-ended stream of reconciling capital expenditures.

Third, the settlement creates a mechanism to fund a range of activities related to grid modernization, identified as Power Sector Transformation ("PST") programs, without creating an additional cost tracker mechanism or expanding the scope of projects funded through the existing ISR mechanism. This approach also is consistent with the arguments the Division advanced that aspects of PST programs are appropriately considered as a core part of the distribution utility.

Fourth, the settlement delivers Power Sector Transformation investments as a part of the Company's core business planning for its operating expenses. Consistent with stakeholder priorities, it also sets in motion a stakeholder engagement process to continue over the course of the multiyear rate plan.

Fifth, the settlement achieves significant reductions in the revenue requirement request of the Company.

Sixth, the settlement establishes the first stage of performance incentive mechanisms to be refined and potentially expanded through future consultation.

Q. What considerations not in evidence in this docket affected the Division's consideration of the settlement?

A. The most significant consideration not in evidence in this docket derives from the recent electric ISR dockets (4473, 4539, 4592,4682). Over the last 5 years, National Grid has overspent its capital budget by 6.8% on average for a total of $27.75 million. Under the current statute, the Company's capital overspend is automatically recovered the subsequent year without any consequences. Expected technology investments over the coming three years will increase the potential risk to ratepayers of capital overspend. The capital efficiency mechanism set forth in section 28 establishes a 3-year capital budget that dovetails with the existing statute and corrects for overspending by and incentivizing the achievement of savings by the company.

III. REVENUE REQUIREMENTS

Q. While the Settlement has many important non-quantified benefits for ratepayers, how does the level of base distribution increases compare to the case that was originally filed, and the amended cases filed by the Company, during the course of the proceedings?

A. There are different ways to make this comparison because the Company's original case did not include any PST costs in the base distribution revenue requirements. But the Division has compared the results of the Settlement in two primary ways. That is, the base distribution increase (without PST) in the first year and the cumulative incremental revenue to the Company over the three-year rate plan each compare very favorably.

Q. How does the base distribution increase without PST compare?

A. Below is a chart that makes that comparison. Please note that the figures shown for the Settlement are rounded from the precise numbers. In any event, there is a substantial reduction in the base distribution component of the revenue requirement below the Company's case in Rate Year 1, under all three of its filings. In addition, the Settlement yields a significantly lower cumulative amount over the course of the three-year plan, when comparing the Total 3-Year Incremental Impact across each case.

		Rate Year 1 Increase	Total 3-Year Incremental Impact
Original Filing	(NO PST)	$71,617,450	$214,852,350
March 2 Filing	(NO PST)	$45,842,884	$137,528,652
Co. Rebuttal	(NO PST)	$34,328,802	$102,986,406
Settlement	(Excluding PST)	**$19,659,000**	**$82,983,000**

Q. What were the annual revenue assumptions used in this analysis for the Company's three filings shown in the chart, when calculating the Total 3-Year Incremental Impact?

A. While the Company estimated revenue requirements for so-called "Data Years 1 and 2" in its filings, the Division used a more conservative assumption for the chart above. Specifically, the chart does <u>not</u> assume any increases in years 2 and 3 under the Company's three filings. Instead, it assumes base distribution remains flat for years 2 and 3, as would happen with a one-year rate case. Even without any base distribution increases in years 2 and 3, however, the Settlement – which does have modest increases in years 2 and 3 – is significantly lower in the cumulative 3-year incremental impact comparison.

Q. What about the PST costs being added?

A. It is, of course, important to take PST costs into account. But if we assume that PST programs would have advanced without the Settlement, then PST costs still would have been incurred by the Company and presumably recovered from ratepayers at some point in the future. We assume cost recovery would have occurred either (1) through the PST tracker which was opposed by the Division and intervenors, or (2) through base distribution rates in the Company's next rate case filing, the timing of which probably would have been accelerated if the Company was required to pursue PST and incur incremental costs without a tracker. For that reason, we believe it is reasonable and appropriate to make a simplifying assumption when comparing the scenarios that the PST costs to ratepayers would have been close, if not identical, in all four cases. Having said this, the Division still believes that costs recovered from ratepayers for PST under the tracker would have lacked budgetary discipline. As a result, the Division believes there would have been a greater risk that ratepayers would have absorbed a higher cost for the PST programs that are now rolled into base distribution under the multi-year rate plan. By including the costs in base distribution in the Settlement, the potential for the "spend the money, get the money" phenomenon that can infect reconciliations is eliminated. The downside, of course, is if the Company can implement some of the PST programs at lower cost than forecasted, then there is no refund to ratepayers for the difference. But the Division believes in the overall scheme of ratemaking, rolling the foundational PST costs into base rates and placing shareholders at risk of performance is a more efficient means to regulate and likely drives costs to ratepayers lower than a tracker would typically yield when the Company has "no skin in the game."

Q. What is the incremental impact of adding the PST programs into base distribution rates?

A. The Settlement has the benefit of locking down most of the PST-related costs in base distribution rates. The combined PST costs included in base distribution is $6.7 million in year one, $4.5 million in year two, and $2.4 million in year three. This results in an additional $31.5 million of cumulative impact. Thus, the Total 3-Year Cumulative Impact of the combined base distribution increases shown in the table above plus the PST requirements, is approximately $114.5 million over three years.

Q. How does this compare to the Company's first two filings?

A. What is important to consider is that when we compare the cumulative impact of the Settlement (including the PST) with the Company's original filing before the tax reduction and the March 2 filing which reflected the entire tax adjustment effect, the cumulative impact of the Settlement is lower, even after the tax reduction is considered. In effect, a portion of the benefits of the corporate tax rate reduction are being used to pay for a significant portion of the foundational costs of transforming the utility business, but we are still obtaining a lower cumulative impact on ratepayers than the company's original two filings when considering the effect of the tax reduction.

Q. Can you summarize how the Division addressed its main concerns from its April 6 testimony relating to base distribution costs, as they impacted the first-year revenue requirement?

A. There were a number of adjustments recommended by the Division in its case. A matrix has been provided with the Settlement that identifies each of the adjustments to the revenue requirement resulting from the Settlement. But I will attempt to specifically address the most significant adjustments.

Q. Please provide an explanation of the ROE result.

A. The Division recommended an ROE of 9% for gas distribution and 8.5% for electric distribution. The Settlement, as indicated elsewhere, establishes an ROE for both distribution businesses at 9.275%. As happens in most settlements of the revenue requirement, this reflects a compromise. But it is not a compromise that is arbitrary. The Division will make its cost of capital witness available during the hearings. Before agreeing to this ROE, the Division confirmed with its witness that 9.275% was a reasonable result. It also is worth noting that the ROE of 9.275% is lower than the current ROE of 9.5%. It also is substantially lower than the ROE's recently granted to electric and gas distribution companies in Massachusetts, which have been around 10%. In addition, it is only slightly higher than the ROE negotiated by the Company's affiliate in New York, which was 9%. Taking all of these data points into account, the result is beneficial to ratepayers in Rhode Island.

Q. Did the Division change its position that the ROE on the electric business should be lower because of Performance Incentives?

A. We have not changed our position, but in this settlement, we compromised. In discussions with the Company, it was readily apparent that no settlement could have been achieved without giving some ground. In the overall scheme of transforming the utility model, implementing PST initiatives, and establishing new sets of PIMs, it was far more important to achieve a settlement than to insist on the position at this time and forgo the multi-year plan. The Division retains its right and intention to pursue this principle again at a later date. In fact, the earnings sharing mechanism on the electric earnings in this settlement requires the earnings from PIMs to be taken into account when determining sharing with ratepayers. While the starting point is not a lower ROE, it establishes a framework the Division supports. If the Commission approves this settlement, it will be the first time that incentive payments are affirmatively considered in the calculation of earnings subject to sharing. From the Division's perspective, the mechanism sends the correct directional signal to the Company that earning above its allowed ROE is permitted through the PIMs and other efficiency measures. This is the same directional signal the Division was recommending in its original filing. In this context, while the settlement is not intended to establish binding precedent for anyone, the experience gained from this first three-year rate plan will be important to evaluate for the next rate filing. The settlement, in fact, requires the Company to file its next rate case after the third year of the rate plan is completed. The next filing must be timed to set rates with an effective date no later than January 1, 2022, unless the Division consents to an extension. At that time, this issue can be revisited with experience in hand.

Q. Can you explain what occurred with the Division's recommendation to reduce depreciation rates which has a combined value of $6.2 million on the Division's position?

A. Yes. Like the ROE, the adjustment reflected in the settlement was the result of compromise. During negotiations – and as may be implicit from the Company's Rebuttal filing – the Company indicated that its accountants were concerned with the methodologies recommended by the Division.   But the Company indicated to the Division that it was comfortable reaching a depreciation outcome that was halfway to the Division's position. While the Division still believes its rationale is valid and reasonable, the parties decided to split the difference on the depreciation adjustment. As a result, the combined adjustment reflected in the settlement is $3.1 million. We urge the Commission to honor this compromise, even if it is not precise in its methodological path to the result.

Q. What about the Division's recommendations relating to Gas Business Enablement?

A. In sum, the Division's core recommendations from April 6 were adopted in the settlement. These core recommendations related to (i) the implementation of a 15%/85% "slippage adjustment", (ii) the inclusion of a special category of "Type II" savings to net against the costs, (iii) a cap on total program costs allocated to Rhode Island, (iv) a flow back to ratepayers to the extent program costs are less than the costs included in the revenue requirement, (v) elimination of the past one-time cost that the Company was proposing to include in rates, and (vi) amortization of the one-time O&M costs incurred during the rate plan period. Each of these adjustments were reflected in the settlement.

Q. Can you explain how the amortization issue was reflected in the settlement?

A. Yes. The Company initially proposed to aggregate multiple years of one-time O&M costs from GBE and amortize them over ten years with a return. The Division proposed that only the rate year costs should be amortized over ten years and recovered with a return. But the Division indicated if there was a multi-year plan, then the forecasted costs over the three-year plan could be included in the amortization and recovered. It was this recommendation that was adopted in the settlement. When the Company returns for its next rate case, it can seek recovery of the balance of the prudently incurred and forecasted costs beyond the rate plan period that have not been included in the amortization.

Q. What about the Division's position on the IT investments?

A. Similar to the GBE 15%/85% slippage adjustment, the Division proposed the same for the IT investments in its April 6 case. This treatment has been adopted for the settlement.

Q. Can you explain what treatment is being given for the addition of the incremental FTEs relating to vacancies and pending retirements?

A. Yes. The Division never took issue with the rationale of the Company filling the vacancies and addressing the retirements. Rather, the Division was concerned that all of the new hires were being contemplated all at once during the rate year. In the settlement, the Company agreed to phase in the new FTEs over the three-year rate plan period. This results in a lower cost in the first year, that rises slightly over the next two years, as the positions are filled. From the Division's perspective, this is a rational way of addressing the issue.

Q. What about the incremental additions relating to DG interconnections?

A. On this issue the Division did change its position. We were persuaded that funding the resources to address DG was consistent with the overarching policy to encourage the deployment of distributed generation, even though we initially were skeptical on the number being proposed. In the end, we are essentially deferring to the Company's judgment in light of the policy directives to enable distributed generation. But here, the Company also agreed to phase in the FTE positions over the rate plan period, rather than filling all the new positions in one year. Given our reconsideration that was influenced by policy and the agreement from the Company to phase in the additions, the Division agreed to support the incremental FTEs relating to DG interconnections on this phased-in basis.

Q. Were there other adjustments recommended by the Division that were included in the settlement?

A. Yes. The settlement also accepted the Division's adjustment relating to capital structure, as well as the debt rates used for the gas business. The settlement also reflects the Division's adjustment relating to the uncollectible rate used in the gas business revenue requirement. In addition, the Company has partially accepted an adjustment to its capital forecast for gas growth advocated by the Division. There also was another Division recommendation that was accepted by the Company in its rebuttal testimony relating to the excess deferred taxes. This too, of course, is reflected in the settlement.

Q. Were there any significant adjustments relating to the base distribution business that were not adopted in the determination of the revenue requirements for the settlement?

A. Yes. The Division had argued for an adjustment to non-union wage increases, using a methodology that was based on the history of union wage increases as a proxy. In doing so, the Division was advancing an argument that would have reflected a shift from past

Commission policy, had it been adopted. The Company responded in rebuttal, maintaining the importance of using market data for analyzing the appropriateness of non-union wage adjustments. While the Division is not conceding the point for future purposes, the Division came to realize during negotiations that it was an issue that was very important to the Company, given the potential implications across multiple jurisdictions. For that reason, the Division dropped this issue as a point of contention for settlement purposes.

Q. Are there other effects on the revenue requirement?

A. There are effects that flow through the revenue requirement as a result of settling on the ROE. Using a new ROE that is slightly higher than what was proposed by the Division and significantly lower than that which was proposed by the Company has flow-through effects relating to taxes, Service Company rents, and the revenue requirement calculations on rate base.

Q. Are there adjustments to base distribution rates in Rate Years 2 and 3 that relate to the non-PST electric distribution business?

A. Yes. In the multi-year rate plan, fixed adjustments are proposed, as shown in the schedules included with the Settlement Agreement. On the electric side, modest base increases (not related to PST) are allowed equal to approximately $3.9 million in Rate Year 2, and $2 million in Rate Year 3. These are largely driven by predictable labor costs, the phase-in of incremental FTEs discussed earlier, depreciation on forecasted non-ISR capital additions, and a very small allowance for other O&M expenses.

Q. What about Rate Years 2 and 3 for the gas distribution business?

A. The effects are very similar for the gas distribution business, except the increases are higher because of the impact of non-ISR capital additions. These are capital additions addressing the growth of the gas business which typically have positive economic development effects. As a result, the Division believes they are appropriate to be supported at this time. For Rate Year 2, the total non-PST adjustment is approximately $5.5 million (approximately $3 million of which relates to incremental depreciation and taxes on incremental rate base from new non-ISR capital investment). For Rate Year 3, the adjustment is $3.2 million.

Q. Why would the Division agree to incremental increases in base distribution rates for years 2 and 3 when a one-year rate case would not provide such relief?

A. The answer to this question relates to the purpose and benefits of multi-year planning. As the Division has already explained in this case, we are moving to change the way the utility business is conducted. The benefits of phasing in new innovations through a multi-year process also come with the need to address the on-going costs of the ordinary business. The adjustments in years 2 and 3, in the larger scheme of ratemaking, are relatively small. In return, we are receiving the full cooperation and “buy-in” of the Company to multi-year planning and the inclusion of the foundational costs of PST in base distribution rates, through which the Company takes the risk of overspending. It also was the Division’s judgment that achieving a multi-year settlement and avoiding a cost-recovery dispute over PST in docket 4780 was not achievable without including some modest relief in years 2 and 3 to cover other very predictable forecasted costs. In turn, the Division and the Commission should have significant visibility to the Company's business through the earnings reports, followed by another rate filing occurring shortly after the end of this multi-year plan.

Q. What are the PST annual costs that are added to the revenue requirement for each year?

A. As I identified earlier, the approximate combined total (electric & gas) of PST costs added to each year of the rate plan are as follows: Year 1 – $6.7 million; Year 2 – $4.5 million; and Year 3 – $2.4 million. All but $2.5 million over the three years – for relatively obvious reasons – are incurred on the electric side of the business. However, there are some improved foundational systems that benefit the gas side of the business. For that reason, $2.5 million is appropriately allocated to the gas business.

Q. In the Division's April 6 case, the Division took issue with what appeared to be an inconsistent way that the Company was proposing to allocate costs for GBE and PST. How does the settlement address this issue?

A. The Division's concern was that the GBE costs were allocated without any pre-conditions for cost recovery, based on cost causation. In contrast, when the Company proposed cost recovery for the PST programs, the allocation of costs for the PST programs that would ultimately benefit other jurisdictions were being conditioned on advance cost recovery being obtained in other jurisdictions. As it has turned out fortuitously, New York and Massachusetts have granted approvals for the foundational PST programs that are being funded in the three-year revenue requirements in the settlement. For that reason, the conflict in this case has been rendered moot for the programs for which cost recovery is provided in this multi-year plan. To the extent the Division perceives inconsistent treatment in the future, the Division certainly would not hesitate to raise the issue again. But it is no longer pertinent to the costs being flowed through the revenue requirements in this settlement. Further, while Massachusetts has not approved any AMI deployment, New York is now on a similar track with Rhode Island for the potential approval and deployment of AMI. In sum, for each of the PST programs being funded in the revenue requirements that are also being implemented across jurisdictions, the rate allowances in the rate plan allocate the lower "multi-jurisdictional" cost to Rhode Island, as opposed to the higher cost that had been alternatively estimated for "Rhode Island only" implementation.

Q. How did the parties resolve the matter of the AMI study?

A. After further discussions with the Company about the scope of the "study," the Division agreed to a rate allowance of $2 million, which is amortized over the three-year rate plan revenue requirements. In those discussions, we also came to realize that calling it a "study" may be a misnomer. It is more akin to an updated business case that includes planning and cost-estimating. It also will consider many issues, including alternative ownership scenarios. The potential deployment of AMI is ultimately going to be addressed in a separate filing. The settlement allows for a re-opener of base distribution rates to address any costs that may be incurred by the Company in deploying AMI, to the extent the costs are incurred during the rate plan period. But Commission approval of AMI is a precondition.

IV. PERFORMANCE INCENTIVE MECHANISMS (PIMs)

Q. What considerations led the Division to revise its performance incentive mechanism design recommendations?

A. The performance incentive mechanisms have the goal of meaningful performance incentives in support of key state energy policy goals. The settlement represents a starting point for the role of performance incentive mechanisms in RI; we believe it will be important for them to grow over time both in terms of their financial significance and their role in driving important outcomes.

Division witness Tim Woolf will be made available at the hearings to answer more granular questions, but the settlement proposes seven performance incentives (across three categories) intended to advance state policy goals and drive benefits for RI customers.

- **System Efficiency**: Annual MW Capacity Savings,
- **Distributed Energy Resources**: Installed Energy Storage Capacity, CO_2: Consumer Electric Vehicles, Light Duty Government and Commercial Fleet Electrification, and CO_2: Electric Heat,
- **PST Enablement:** Awarded Low-income and Multi-unit EVSE Sites; and Interconnection: Time to Interconnection Service Agreement (ISA)

Q. Please describe how the incentive levels were set for the performance incentive mechanisms?

A. For each of the performance incentive mechanisms above, the value of the incentive has been established using the following steps:

- the quantified net benefits of the relevant initiative were estimated using the Company's BCA assumptions and methodology;
- 45% of the quantified net benefits were used to determine the utility incentive, the remaining 55% of net benefits will go to customers;
- the utility incentive was increased to account for unquantified benefits, in terms of improved reliability and market transformation of distributed energy resources;
- the utility incentive was estimated both in terms of dollars and basis points, using the return on equity that was agreed to as part of this rate case settlement.

When the Company achieves one of the PIM targets, it will receive an incentive based upon the dollar value associated with the relevant target; not the basis points.

The magnitude of the utility incentive will be based upon the BCA results used at the time the Commission approves the PIM. The utility incentive will not be modified based on after-the-fact reassessment of benefits and costs of the initiatives. Establishing a certain and meaningful incentive value is essential in order to most effectively drive Company performance in the delivery of the objectives supported by these incentives.

V. POWER SECTOR TRANSFORMATION INITIATIVES

Q. What PST initiatives are addressed in the settlement?

A. In addition to the AMI study – which we also refer to as the updated business case – there are two other categories of initiatives that were directly addressed. One category relates to certain foundational initiatives. The Division had argued in its April 6 case that these should be considered core distribution functions. The second category was "special sector programs" which do not necessarily relate to the core the distribution business, but the parties believe are very important to address.

Q. What foundational initiatives are addressed?

A. Through this settlement, the Company commits to move forward with certain initiatives, without the PST cost recovery tracker that had been proposed in docket 4780. I will not re-describe each initiative here, because they are described in the Company's original PST filing in docket 4780. But the list includes: GIS Enhancements, the System Data Portal, and DSCADA, among several other related initiatives. The costs of these initiatives that will be incurred during the rate plan period are included in the base distribution revenue requirements for each year. From the Division's perspective, this is significant. The fact that the costs are included in base distribution like other run-the-business costs of operating the system is foundational, in and of itself.

Q. What are the other foundational initiatives that you referred to generally in your list?

A. These initiatives which are identified in the Company's PST filing include Enterprise Service Bus, Data Lake, PI Historian, Advanced Analytics, Telecommunications, and Cybersecurity.

Q. Were there any foundational-type initiatives that have been excluded?

A. Yes. The Company agreed with the Division's recommendation not to pursue the next phase of feeder monitor installations, due to the potential for the advancement of AMI.

Q. Are the costs of the foundational initiatives that have been included in the revenue requirement subject to reconciliation?

A. No. The Company will have the responsibility to implement the initiatives in the same manner that it conducts its base distribution business. Similar to what the Company needs to do with the rest of its business, the Company needs to manage the costs and assume the risks if the project costs exceed the budget. Conversely, if the Company can implement the projects efficiently, the Company benefits from the cost savings. The risks are all on the Company.

There is one additional feature that relates to DSCADA. While the costs are not being reconciled, the revenue allowance attributable to the project will be accounted for separately to address the circumstances that could arise out of a delay in implementation. This was established because the most efficient implementation plan for DSCADA requires close coordination with the Massachusetts affiliate. Thus, while the costs are included in Rate Year 2, it is possible that the projects will not advance until later. Should there be a delay, a deferral would be booked by the Company equal to the rate allowance and the allowance applied against the costs incurred in a later year.

Q. What are the Special Sector Programs that are being funded in the settlement?

A. There are three. Electric Transportation, Electric Heat, and Energy Storage. I will not describe the details of these initiatives which are set forth in the Settlement Agreement. But the Division supports moving forward these on the terms set forth in the settlement.

Q. How is cost recovery addressed for the Special Sector Programs?

A. The costs are not being reconciled for recovery, but the Settlement Agreement contains a separate section which requires the program costs to be tracked against the rate allowance – as described in Section 20(d). Because there are many factors associated with these three initiatives that are largely out of the control of the Company, the parties believed it was important to track the costs against the rate allowance. To the extent the costs incurred are below the rate allowance, a deferral will be created, where the funds can either be used later for the same program or allocated to another sector, as more specifically described in that section. To the extent the costs exceed the rate allowance, the Company is at risk. However, it is recognized that it may be in the interest of ratepayers to allow the cost recovery, to the extent the Company's actions were consistent with the program intent and were prudently incurred. However, unlike other reconciliations that provide a right to the Company to recover all prudently incurred costs, recovery in this instance would be left entirely to the discretion of the Commission.

Q. Does stakeholder engagement on PST continue under the settlement?

A. Yes. This is an important feature. Section 17(e) of the settlement proposes to create a "PST Advisory Group" that will continue engagement with the Company as it moves forward. In particular, the Company will need to make two important filings with the Commission during the rate plan period. The first is the filing of the AMI plan. The second is the filing of a Grid Modernization Plan which links to the AMI. The PST Advisory Group will be able to engage with the Company on the scope and parameters of the program proposals even before they are filed with the Commission. Finally, the PST Advisory Group or a subcommittee from the group will be able to continue dialogue with the Company on the Special Sector Programs.

VI. <u>RATE DESIGN ISSUES</u>

Q. How did the Settlement resolve the electric residential rate design issue relating to the fixed customer charge?

A. The settlement proposes a very modest increase from \$5.00 to \$6.00, essentially reflecting a compromise among all the parties. In effect, this is consistent with the Division's view that any material changes to the fixed customer charge for residential customers should wait for the docket when time-varying rates are being considered in the context of AMF deployment.

Q. Were there other rate design issues resolved by the settlement on the electric side?

A. Yes. I will not elaborate here, but resolution of the issues includes agreement on the consolidation of the G-62 and G-32 rate classes, changes to the S-05 Streetlighting tariff to address concerns raised by NERI regarding the need to accommodate streetlight dimming, an adjustment to the allocation of costs to the X-01 rate that serves Amtrak, and a commitment by the Company to waive the demand ratchet for the Navy when the Hurricane Barrier needs to operate under emergency conditions during peak hours. The Division supports all of these proposals.

Q. What about rate design issues on the gas side?

A. The parties also agreed to a modest increase in the residential fixed customer charge on the gas side, moving to $14.00, where the Company had sought an increase to $16.00. There also were some other small matters that were addressed. As a separate issue, the Company agreed to the Division's recommendation that demand billing units for medium, large and extra large C&I customers be normalized in future rate cases. There also was agreement on the returned check fee, which has been changed for both gas and electric to $8.00. There also were some other agreements on a few other gas-related matters that are set forth in the issues matrix that was filed with the Commission.

Q. What is the proposed outcome for low income rate discounts for electric and gas customers?

A. The settlement proposes a substantial change in the discount that should provide significant relief for low income customers across the state. The agreement proposes a "total bill" discount of 25% for both electric and gas service to eligible customers. In addition, for customers receiving benefits through Medicaid, General Public Assistance, and/or the Family Independence Program, an additional discount of 5 percent off of the total amount billed will be added. The application of these discounts actually result in rate decreases for both electric and gas customers eligible for these rates. The Division is very pleased to be able to address the financial need of these customers who face special challenges to pay their monthly bills.

VII. CONCLUSION

Q. Do you have any other general comments about the settlement to add?

A. Yes. If approved by the Commission, this settlement has the potential to provide a very important first step in making a significant directional change in the regulatory model. It moves the Company away from "one-year-at-a-time" regulatory processes and toward long-term planning that is needed to transform the business. This is not to say the Company is not supportive of long-term thinking, but the regulatory paradigm needs to be aligned to effectively support the type of sea-change that has been contemplated in the Power Sector Transformation process that began months before the Company filed this rate case.

Q. Is the Division fully satisfied with all components of the agreement?

A. The Division is very pleased with the proposed outcome as a whole. But, like most settlements, it consists of a series of compromises. When compromises occur, each party with different perspectives must give in order to receive. This two-way street of negotiation means that the “very good” often is accompanied by features that must meet the competing needs of others in the negotiating room. In that sense, I believe it is fair to say that all the parties who worked hard to negotiate a settlement in good faith were eventually able to recognize the importance of not letting the perfect be the enemy of the good. This settlement surely is not perfect, but it provides the first big step toward changing the way the utility model has operated for a long time.

The Division is aware that the Commission has an important role to assure that the outcome proposed by the settlement is just and reasonable, under the traditional standard of ratemaking. The Division sincerely hopes that we and the other parties can answer all of the Commission’s questions and address any concerns the Commission might have, in a way that will allow the Commission to comfortably approve it, with all of its carefully negotiated features.

Q. Does this conclude your testimony?

A. Yes.